ELECTRICITY SYSTEM DEVELOPMENT
IN THE 1990s IN INDIA

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I. INTRODUCTION

The power industry is very capital intensive. That efforts so far have concentrated largely on supply enhancement -- and particularly on expansion of generating capacity -- can not be denied. Owing to the facts that utilization of existing thermal capacity remains below the desired levels, the financial situation of power utilities is not healthy, the substantial power shortages (despite the fact that the power industry has accounted for over 15% of total planned investment in the country for the past 20 years) and a host of other problems, it is becoming increasingly evident that the single - minded approach towards supply enhancement is not adequate.

These are perhaps the reasons why it becomes important to review the evolution of the power supply industry over the past decade or two, in order to derive an understanding of the possible directions it should take in the future. It needs no reiteration that such a review should cover aspects like financial performance, institutional structures and their limitations, demand management, and environmental concerns.

A review of the power supply industry during the last 15 years or so is relevant for several reasons, the most important of which are listed below. Compared to about 64,000 MW of total installed generating capacity today, the capacity at the beginning of 1975/76 was less than 20,000 MW. Moreover, less than 200,000 villages had been electrified in 1975/76 compared to over 460,000 today. Further, the central sector power corporations (like the

National Thermal Power Corporation or NTPC etc.) which are now very important actors on the national electric power scene, came into existence only after 1976. The 210 MW and 500 MW thermal power unit sizes, which are now accepted as standard sizes for coal fired generating capacity, were first introduced only in the late-1970s and mid-1980s respectively. And problems associated with burning large quantities of low-grade coal (and the fast deterioration in coal quality due to rapid increases in open-cast mining) also surfaced in the 1980s.

Of the nearly 64,000 MW of utility-owned generating capacity in India at the end of 1989/90, less than 20,000 MW is hydro capacity, the remainder being thermal -- mostly coal-fired steam thermal capacity, but also including lignite-fired thermal plants, oil and gas fired gas turbines and nuclear plants. The share of hydro capacity has reduced from over 42% in 1975/76 to about 33% in 1989/90. Although it is not easy to judge an optimal or a desirable mix of hydro and thermal capacity (it would depend on several factors, including the system load curve and the performance of various types of power plants and so on), the continuous decline of the hydro share has caused significant concerns. These concerns relate to the environmental problems (particularly ash handling and disposal) and the financial situation of utilities as they have to spend heavily on fuel purchases.

Several important performance indicators of power utilities in India are presented in subsequent sections, and the issues which impede enhanced performance by power utilities are deciphered. Policy initiatives that may be necessary to improve the situation are also analyzed. It needs no reiteration here, that the reasons for "below-desirable-level" performance on one "account" (say technological) are linked to a variety of factors that go beyond the realm of that "account" (for instance, poor thermal efficiency of power plants is not only related to poor quality of coal, but also to the rather poor financial position of the utilities) as will become clear subsequent sections. It therefore seems relevant to address as wide a variety of performance indicators, as is possible.

The power industry is a "concurrent subject" in India, i.e. it falls under the purview of both the central/federal Government and the state/provincial Governments. Consequently, there are over 20 power utilities in the country. In this report, to the extent possible, the all-India situation is presented, but where utility-specific data are required, the focus is on one of the "best" and one of the "worst" utilities. For illustrative purposes, performance indicators of the Tamil Nadu Electricity Board (TNEB) and the West Bengal State Electricity Board (WBSEB) respectively are presented.

II. MACROECONOMIC TRENDS

The gross domestic product (GDP) of the Indian economy has been growing at an average annual growth rate of 3.9% since 1950, although the actual growth rates achieved have been anywhere below 10%. An analysis of the GDP growth rate indicates that although the fluctuations have become increasingly more pronounced in successive decades, the average growth rate has increased only from 3.9% in the 1950s to 4.9% in the 1980s. During his period, the share of the primary sector of the economy (agriculture, mining and manufacturing etc.) has steadily decreased at a rate of about 0.7% per annum while the shares of the secondary (transport, communication etc.) and tertiary (community and personal services) sectors have increased at the rates of about 1.7% and 1% per annum, respectively. In 1986-87, the percentage share of the three sectors to the GDP were 61.1, 27 and 11.9% respectively. This pattern of growth is unlikely to change in the next decade or so. The secondary and tertiary sectors of the economy will continue to grow in order to meet the demands of about 30% of the population which has a very large purchasing power. On the other hand, the primary sector will continue to provide majority of the employment in the economy and cannot, therefore, be expected to stagnate or decrease in absolute terms. During the 1980s, the primary sector increased at about 4.2% per annum: industrial growth occuring at about 7.3% p.a., while agricultural growth was almost static at about 1% p.a. The growth in the secondary and tertiary sectors was 5.9% and 6.2% respectively. The total GDP in 1987-88 was approximately Rs.1704 billion.

Official documents forecast a growth rate of 6% p.a. of the Indian economy. However, this implies a growth rate of about 10% for industry and 4.5% for agriculture. Both these rates seem to be on the higher side: due to lack of financial resources for industry, and lack of land for further expansion of agriculture. Growth rates of 8% and 3% for industry and agriculture seem achievable: GDP growth rate would, consequently, be 4.5 to 5% per annum.

23.7% of the population lived in urban areas in 1981. The urban population is expected to double every twenty years and by the turn of the century, India will have the largest urban population in the world (of the order of 350 million). This population will probably be living in a total of about 5,000 urban areas, although just 500 of these towns and cities will account for over 60% of the total urban population.

One important underlying trend here is the rapid growth of the power sector. In fact, it has been the fastest growing sector in India. Electricity has also accounted for a major share of public sector investments in the past two decades or so.

III. TECHNOLOGICAL CONCERNS

3.1 Generation

Tables 1 and 2 show the average heat rates of coal-fired steam thermal power stations operated by TNEB and WBSEB respectively. It is evident that the thermal efficiency of the coal-fired capacity in Tamil Nadu has increased substantially since the mid-1970s; and that in West Bengal has also shown a similar trend although the efficiency has declined somewhat in the latter half of the 1980s.

These observations are very general and tell very little about the actual operations of power plants. First, the quality of coal has declined considerably; the average calorific value of steam grade coal being about 4600 kCal/kg in 1975/76 and 4000 kCal/kg after 1984/85. This trend in itself may not effect the heat rate if care is taken to provide adequate oil support. For it is understood that units of (say) 210 MW capacity, designed to use 4500 kCal/kg coal, have been getting increasingly inferior quality of coal. In such a situation, even if the coal feed rate (in tonnage per hour) to the boiler is maximum, the unit cannot generate to the rated capacity, because the effective calorific intake in the boiler is less than the design value. Therefore, increasing amounts of oil need to be fed in to the boiler with deterioration in coal quality. However, if this is not done, then the unit operates on a higher point on the heat-rate curve -- and display a lower thermal efficiency.

Similarly, as a large part of the generating capacity that has been added in the past 15 years is coal-fired, these power stations have been used to a certain extent for peaking purposes. In actual practice, as it takes several hours to start a coal-fired unit (4 or more hours even under hot-start conditions), the units are made to generate (say) one-fourth of their rated capacity at all times, i.e. even during off-peak periods. Under these circumstances also, the oil support needed is rather high, and the thermal efficiency of the units is low as they are operating on a high point on the heat-rate curve.

Nevertheless, Table 1 indicates that TNEB has been successful in improving the power plant efficiencies. However, this may be due in large part to the fact that the overall plant load factor of its coal-fired power stations has increased from 27.8% in 1975/76 to 54.2% in 1986/87. On the other hand, for WBSEB such a clear trend on plant load factors is not visible. In fact, the correlations between data in Tables 1 and 4 and between Tables 2 and 6 clearly shows that plant load factors have a very significant impact on overall thermal efficiencies.

The plant load factor (PLF) is in fact very specific to each generating unit. In addition to the maintenance and forced outage rates (which depend on maintenance practices, availability of spares etc.) and the power demand at different times of day and different months/seasons, it also depends on whether the particular unit has stabilized or not (this is discussed later). Table 9 shows that for units in operation for three years or more

(i.e. stabilized units), the load factors in the TNEB system in 1988/89 varied from 26.51% to 88.66%; while the corresponding range in 1987/88 was 50.01% to 78.94%. For both years, it is evident that the performance of units at the Ennore TPS is much below the average in Tamil Nadu, while that of the Tuticorin TPS is the best. Similarly, Table 10 shows a range of plant load factors for coal-fired units in West Bengal. As expected, the best and worst PLF in WBSEB is much below that in TNEB.

Owing to the overall power shortage situation, the general trend is that all power stations generate power to the extent they are able to and whenever they can -- the only exception being at night times in certain states and certain seasons, when some states may have some surplus generating capacity at their disposal, and are forced to "back-down" some of their thermal plants. Table 7 shows that the overall average PLF of thermal plants in India declined from about 52% in 1975/76 to 44% in 1980/81 (as coal shortages surfaced) and then increased to 50% by 1984/85 and further on 56.5% by 1987/88 as more experience was gained in operating 210 MW and 500 MW units, renovation and modernization schemes improved the performance of some of the old or chronically troubled units, and the coal availability position improved.

As far as hydro power capacity is concerned, the load factor is influenced by the availability of water. In particular, if a hydro power station is a "multi-purpose" project, the water availability would not merely be linked to the quantity of water collected or flowing into the reservoir, but also to the releases

for canal-irrigation. It is clear therefore, that hydro power generation is influenced by rainfall conditions -- in a less-than-normal rainfall year, the problems of low water levels in the reservoir are compounded by the increased need for canal irrigation. Therefore, it is generally not possible to draw any firm conclusions on the performance of hydro power stations from data on load factors. Tables 5 and 8 give the load factors of hydro power stations in TNEB and WBSEB systems since 1975/76. The load factors in Tamil Nadu have generally been in the 35% to 40% range, and the low load factor of 25% in 1986/87 is becuase that was an exceptionally low rainfall year for Tamil Nadu. Similarly, Table 10 for shows that the load factors for hydro capacity in WBSEB and DVC are in the range of 15 to 40%.[1)]

As the PLF of thermal power stations is less than 60% (as discussed above) and as they account for over 65% of the installed capacity, this leads to a situation when in 1988/89, a total installed capacity of nearly 59,100 MW could serve a total peak demand of only 34,800 MW [2)] in the country. This means a reserve margin of nearly 70%. In fact, reserve margins in India have been 60% or more in the 1980s (see Table 19). However, it must be borne in mind that the high reserve margin is not a reflection of over-capacity in the system, but of poor plant performance and other aspects (such as improper inter-utility exchange of power, as discussed later).

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1) Damodar Valley Corporation (DVC) is a utility that supplies power to West Bengal, Orissa, Bihar in the Eastern Region.
2) This is the sum of non-simultaneous peak demand in various regions. The simultaneous peak demand would therefore be less than 34,800 MW.

As pointed out earlier, one of the reasons for the high reserve margin is the low plant availability. As a large number of coal-fired units have been established in the 1980s, the overall peaking capability will always seem low as thermal units often take three years to stabilize. In fact, the general trend for coal-fired units which have a PLF of 61% is that they generate 2500 kWh/kW of installed capacity in the first year, 4000 kWh/kW in the second year, about 5000 kWh/kW in the third year, and 5350 kWh/kW from the fourth year onwards.

Of course, availability and PLF of thermal power units have a substantial scope for improvement. The availability of thermal power generating units in the developed countries is significantly higher than what my be considered as normative (for power sector planning purposes) in India. This may be due to several factors: poor quality of coal used in boilers, lack of coal processing facilities, unavailability of a properly trained work force, inadequate or insufficient control equipment, and so forth. The fact that the peak availability norms adopted for planning purposes during the Seventh and Eighth FYP periods are lower than those of the Sixth FYP period, is only a reflection of the recognition of the difficulties experienced.[3] It may be noted that these norms (for planning purposes) are quite different from the actual experience in the recent past from 1977/78 to 1982/83: outage for planned maintenance 12.4%, forced outage rate 18.5%,

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3) FYP : Five Year Plan;
Sixth FYP Period : 1980/81 to 1984/85;
Seventh FYP Period: 1985/86 to 1989/90;
Eighth FYP Period : 1990/91 to 1994//95.

partial outage rate 20% and auxiliary consumption 12%. There is some improvement in the latter half of the 1980s, but it is clear that the availability norms adopted even for the Seventh and Eighth FYP period are based on an a priori assumption that the performance of thermal power stations will improve. In fact, according to available information, the maximum number of outages are due to problems in the boiler, followed by miscellaneous electrical and mechanical faults, while turbine problems come only third.

While peaking capability norms for thermal units are low, those for hydro units are substantially high. The planned unavailability of hydro units during peak time is taken as nil, only because their maintenance work can be scheduled during off-peak periods and in months/seasons when the water availability is low.

3.2 Transmission and Distribution

Transmission and distribution (T&D) losses in Indian utilities increased, on an average, from 17.5% in 1970/71 to 21.7% in 1985/86, and then levelled off to about 21.5% during 1986/87 and 1987/88. The most important reason for high T&D losses is the lack of adequate investment in T&D systems; another reason is the rapid increase in rural electrification when long lines are extended to serve relatively small loads. A downward revision of the T&D outlay for the Seventh FYP period from Rs.220,000 million (as recommended by the Working Group on Power) to Rs.90,000 million, resulted in shelving all T&D system improvement schemes.

This is despite the fact that a 1% reduction in overall T&D losses is estimated to be equivalent to an addition of 380 MW of generating capacity or energy generation at Rs.0.5/kWh (Advisory Board on Energy, "The Energy Scene", Government of India, New Delhi, 1986).

Tables 11 and 12 present the T&D loss estimates for TNEB and WBSEB systems respectively. The T&D losses in the TNEB system have been higher than 17%, while in WBSEB, there seems to be an upward trend. However, these losses are computed from data on generation, exports/purchases, imports and sales; and sales to agricultural consumers are not measured but only estimated. It is the opinion of several agencies (including the Planning Commission and the Central Electricity Authority) that utilities often overestimate sales to agricultural consumers in order to conceal the true level of T&D losses in their systems.

From available data, it is very difficult to estimate the per cent T&D loss levels at various voltage levels, as well as to distinguish between losses arising from technical and commercial reasons. However, some idea may be gained from a study conducted by TERI for the Delhi Electricity Supply Undertaking (DESU), a utility which operates in the Delhi/New Delhi area. As per the findings of this study, the total T&D losses of 22% in the DESU system comprise about 8.6% technical losses and 13.4% commercial losses. Of the 8.6% technical losses, the losses at the 33 kV and higher voltage levels are less than 2%. The commercial losses include losses arising due not only to slow meters and meters not working, but also due to: (i) pilferage of electricity by

consumers who do not have a legal service connection; (ii) bills may not be presented to consumers on time; and (iii) bills may not be paid for in time. The latter two factors for determining commercial losses are important because losses are computed from data on generation, exports, imports and sales of power, where power sales are derived from actual revenue realizations.

In general, there is significant scope for reducing losses in the low tension part of the T&D system. However, the concerned utilities need to conduct detailed analyses before establishing priorities for reducing technical losses in their T&D networks. Likewise, means of reducing commercial losses must also be reviewed.

For power system operation and planning purposes, the entire country is divided into five regions.[4] In addition to the power plants owned and operated by the state power utilities (i.e. state sector power stations) there are central sector power plants also.[5] Although the generation from central sector power plants

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4) The five regions are Northern, Western, Southern, Eastern and North-Eastern. The Northern Region includes Haryana, Himachal Pradesh, Jammu & Kashmir, Punjab, Rajasthan, Uttar Pradesh, Chandigarh and Delhi. The Western Region includes Gujarat, Madhya Pradesh, Maharashtra, Goa, Daman-Diu, Dadra and Nagar Haveli. The Southern Region includes Andhra Pradesh, Karnataka, Kerala, Tamil Nadu, Pondicherry and Lakshadweep. The Eastern Region includes Bihar, Orissa, West Bengal, DVC, Andaman and Nicobar Islands, and Sikkim. The North Eastern includes Assam, Manipur, Meghalaya, Tripura, Arunachal Pradesh, Mizoram and Nagaland.

5) Power plants operated by central sector agencies like NTPC, National Hydroelectric Power Corporation (NHPC), Nuclear Power Corporation (NPC), Neyvelli Lignite Corporation (NLC) etc., which supply power to all states and union territories which constitute the region. The sale of power to the states and UTs is as per pre-specified shares.

is sold to the different states/union territories (UTs) as per some preallocated shares, there is little direct inter-change of power between states. In fact, the situation is such that even when one of the states has surplus hydro capacity and a neighbouring state has to use some old inefficient thermal units or has to resort to power cuts, the inter-state power sales may not in fact take place. A major reason is that the tariffs for inter-state power exchanges are not usually agreeable to all concerned states. It is evident that such a situation leads to inefficiencies in the power system operations. For the situation described above, one state may have to spill water from its hydro reservoirs while its neighbouring state may have to use old oil fired units which have high running costs.

Clearly, it is very important to take steps to develop a tariff-regime for inter-state power exports and imports that would be agreeable to all states. One of the options may be to develop appropriate time-of-use tariff structures; this would of course mean that time-of-day meters be installed at the high tension inter-state transmission lines.

A similar time-of-use tariff structure is also envisaged for power sales from central sector power stations to various states/UTs. The major problem here is that the state/UT utilities are obliged to purchase poewr from the central sector power stations even when they do have available capacity to increase their own generation. The basic idea here is good -- in that the more efficient and new plants of NTPC etc. operate more than the

old state sector plants. However, this also leads to a situation where one state which has a "comfortable" capacity-availability position continues to draw its full share, while at the same time a neighbouring state in the same region faces a "deficit" situation even while it draws its full share from the central sector power stations -- for under-drawal of central sector power by one state and over-drawal by a neighbouring state would be equivalent to direct power exports from the former to the latter!

Furthermore, as the performance of a power station is usually judged on the basis of its load factor, the central sector power stations generate the maximum possible output at all times (and the state/UT utilities have no choice but to purchase that power) while the state/UT power stations are operated to generate power to the minimum possible level, i.e. they operate at a high point on the heat rate curve. Therefore, it may be argued that in the overall interests of power system efficiency, it would better to judge the performance of power stations on the basis of availability of capacity, rather than on load factors achieved.

3.3 Power Deficits

As mentioned before, there are significant power shortages in the country. Estimates of peak and energy deficits are made by the utilities, but these estimates do not usually present the correct picture. For instance, it is known that many types of consumers adjust their electricity usage pattern in anticipation of power supply restrictions imposed on them -- for instance, they may not invest in certain electrical appliances. Moreover, several consumers who desire to obtain a service connection have to wait for several years. Furthermore, as utilities are aware

that they will not be able to meet the power demand of all categories of consumers, they notify power cuts to their consumers in advance (for instance, a 10% or 20% power supply restriction to high-tension consumers during peak hours of 6:00 PM to 10:00 PM). The estimates of power deficits made by the utilities are in fact based on the "notified power cuts" only. However, in reality, certain consumers may also be subject to power cuts due to breakdowns in the transmission or/and distribution systems -- or due also to unexpected breakdowns in the generating power stations themseleves. The actual level and extent of power cuts of course can be found out by compiling the information recorded at various grid substations. However, as there are several hundreds (or even thousands) of substations working in a utility T&D network, this information is never compiled systematically.

In fact, power cuts are imposed only as a last resort. To the extent the load can be sustained in the system without allowing the frequency to fall below the stipulated value of 48.5 Hz (according to the Electricity Supply Act, the normal frequency should be 50 Hz, and the tolerance limits allowed are +/- 3%), this is done. Therefore, even the consumers that are supplied power may not get it at the normal frequency most of the time. The same is true of the supply voltage also.

It is clear therefore that the actual power supply situation is quite poor. Yet the Central Electricity Authority (CEA) uses a normative loss-of-load-probability (LOLP) of 5% for planning purposes. This of course highlights problems associated with the entire power system expansion planning effort, as discussed later.

3.4 Captive Generation

Owing to peak and energy deficits in the utility power supply, and the stated Government policy of preferential power supply to rural areas, several industrial and commercial establishments in urban areas have installed captive generation facilities. The term "captive" here refers to the fact that the power generating equipment so installed is used to meet only one's own electricity requirements. Captive generation in the residential sector is also not unknown.

Captive or non-utility generation may be divided broadly into three distinct economic categories: (i) Cogeneration, where process heat and electric power are produced simultaneously; (ii) Stand-by captive generation, which is used as a back-up in the event of a failure of utility power supply; and (iii) Pure captive generation, which is used to augment utility supply to meet power requirements. Stand-by and pure captive generation is fossil-fuel based. It is not planned by the organized power supply sector, and is a result of decisions taken by individual electricity consumers -- in effect, it is a short term response to the power shortage situation.

The CEA compiles some information relating to non-utility generation systematically, but only from industrial units which have captive capacities of over 100 kW or a contract demand of at least 500 kVA. The most recent period for which such information is available, is 1985/86.

Non-utility generating capacity (as per data available from the CEA) has remained at about 10-11% of the total installed utility capacity in India since 1970/71. However, its average utilization rate has declined from over 3200 kWh/kW in 1975/76 to less than 2500 kWh/kW in 1985/86.

Cogeneration is the combined generation of heat and power. Although it increases the overall efficiency of an industrial process and is desirable from the viewpoint of energy conservation, investment in cogeneration facilities has lagged behind in India. The technology is fairly well understood, but it is the buy-back arrangements with the utilities that need further clarification. As industries which invest in cogeneration would prefer that all their heat or steam requirements be met, the chances are that the equipment installed leads to a situation when they have to sell some power to the utility grid at certain times and to purchase power from it at other times. It is precisely this problem that is now under active discussion in various states. In fact, this is being discussed under a wider framework of power wheeling -- whereby a particular industry could generate power in one part of the state and purchase power for use in its industrial establishment in another part of the state. This power wheeling arrangement is being discussed particularly with reference to windfarms. It may be noted however, that all cogeneration schemes or other power wheeling arrangements would require a suitable amendment of the Electricity Supply Act. At present, electricity consumers are allowed to generate power, but only for their own use, and that too with the prior

sanction/permission of the concerned state/UT electric power utility.

On a technical basis however, it is evident that several industries display a sizable potential for cogeneration. In 1983, the Inter-Ministerial Working Group had identified several major industrial and other consuming sectors where cogeneration systems could be deployed. Their findings are summarized below :

(i) Textile mills, which require large amounts of process steam;

(ii) Cement and brick kilns which require large amounts of high temperature process heat. The gas turbine exhaust with or without supplementary firing can supply this heat and produce captive electric power for factories;

(iii) Chemical process industries such as sulphuric acid manufacture, dyes, intermediate compounds, organic compounds, refineries, fertilisers etc. which require simultaneous steam and power. It is possible to meet part or full heat and power requirements of such chemical complexes using appropriate steam turbine prime-movers and gas turbines with heat recovery systems;

(iv) Glass melting furnaces which exhaust large quantities of hot flue gases. Heat from the exhaust gas can be recovered in waste heat boilers and the steam thus produced can be expanded across steam turbines to produce electricity. Alternatively combined cycle systems, with gas turbines and condensing steam turbines may be installed;

(v) Commercial establishments, hospitals, educational institutions etc. which require heat for space heating and

electricity for lighting etc. Heat can be generated through a boiler and allowed to expand across a turbine to generate power, and waste heat from the generating process may be used for space heating. It is also possible to combine gas turbines or diesel engines with heat recovery devices to meet both power and space heating requirements;

(vi) Oil fields that require high pressure steam for injection into the oil bearing formations to stimulate wells for enhancing the production of crude oil. Gas turbine exhaust heat can contribute its heat content and at the same time provide the air necessary for combustion of additional fuel required to raise steam at high pressures in waste heat boilers;

(vii) Sugar factories, where power is traditionally produced in steam turbines using bagasse. Here it is possible to superimpose topping turbines on existing turbine systems to generate additional power. However, this would require replacement of existing boilers by higher pressure units. Augmentation of existing power capacities is possible also in various categories of industry; and

(viii) In cold climates, municipal wastes can be used as fuel in incinerators for generating steam for meeting heat and power requirements of buildings, districts, townships, municipalities, etc.

In 1977, the National Productivity Council (NPC) had conducted a macro-level study on the feasibility of industrial

cogeneration in a wide cross-section of Indian industry. They had determined the cogeneration potential on a site-by-site basis, with regard to suitably tailored power steam cycles. Their findings are : (i) in 3 pulp and paper factories with a total power demand of 37.5 MW, the cogeneration potential is 56 MW; (ii) in 4 refineries with a total power demand of 37.3 MW, the cogeneration potential is 40 MW; (iii) in 9 chemical plants which have a total power requirement of 33 MW, the cogeneration potential is 47 MW; (iv) in 9 fertilizer plants, which have a total power demand of 193 MW, the cogeneration potential is 250 MW; and (v) in 3 rayon manufacturing plants with a total demand of 17.1 MW, the cogeneration potential is 28 MW.

The sample of 28 industrial establishments therefore displayed a total cogeneration potential of 421 MW. The actual cogeneration potential would be much higher -- for instance, there are 12 refineries operating in India, of which only 4 are included in the NPC sample. It is evident that if legislative and financial concerns are given adequate attention and get sorted out, the cogeneration option can go a long way in improving the power supply position in India.

3.5 End-Use Efficiency

There is substantial scope for improving the end-use efficiency of electricity consumption in all sectors. In most cases, the technology is well-known and well understood, but a lack of adequate institutional and financial mechanisms have impeded the progress of end-use efficiency improvements. For

instance, in the industrial sector, the consumers often use over-sized motors with a low power factor. As these motors do not operate at rated loads, their efficiency is below the optimal value. Furthermore, as those motors have often been in use for several years and are hand-wound because motors that have burnt-out once are repaired manually), their efficiency is often low. However, such motors are easily available, and there is also a well-established second-hand market for such motors.

Such motors are also generally preferred because they are rugged enough to withstand the frequency and voltage fluctuations in grid supply. Their inherent inefficiency often does not impose a heavy burden on industrial consumers as electricity costs are a small fraction of total production costs -- and in any case, certain major electricity consuming industries prefer to use their own captive generation facilities continuously rather than relying on utility grid supplies.

Petrochemicals and paper industries are not electricity intensive. However, aluminium and steel industries are, and the energy use and efficiency issues are highlighted for these industries.

Data on value added in various manufacturing industries are not readily available. However, value added data are indeed available for groups of industry -- metals and alloys as one category, and paper and paper products as another category. Clearly, these include a very heterogenous set of manufacturing industry. For instance, metals and alloys include iron & steel,

aluminium, copper, zinc and other metal/alloy industries. Nevertheless, the available data do indicate the overall trends in electricity consumption intensity. For instance, as far as the metals and alloys sector is concerned, the electricity intensity reduced from 1975/76 to 1980/81 and then increased by 1984/85. However, this may reflect both a change in the capacity utilization of the existing plant, as well as changes in the technology and equipment for processing during the time period.

At present, six smelters are operated by four companies: (i) The Bharat Aluminium Company Ltd. (BALCO) at Korba in Madhya Pradesh: (ii) The Indian Aluminium Company (INDAL) at Belgaum in Karnataka, Hirakud in Orissa, and Alwaye in Kerala; (iii) The Hindustan Aluminium Company Ltd (HINDALCO) at Renukoot in Uttar Pradesh; and (iv) The Madras Aluminium Company Ltd. (MALCO) at Mettur in Tamil Nadu. The smelters at Korba, Belgaum, Renukoot and Mettur are integrated plants, i.e., all process steps for converting bauxite to the finished product take place at the same location. For the INDAL smelters at Alwaye and Hirakud, alumina is the input material -- this alumina is produced at INDAL's alumina plant at Muri in Bihar.

The installed capacity and production of the aluminium industry has grown steadily over the last ten years or so. The two major energy consuming steps are : (i) bauxite ore conversion to alumina; and (ii) production of aluminium from alumina.

Electricity is the major source of energy utilized in smelters for aluminium production. Petroleum coke, coal tar pitch

and coke, which may also be used as an energy fuel, are required for anode making. The electricity intensity at BALCO and MALCO is relatively high, mainly because of unavailability of adequate and steady power supplies -- which lead to frequent shut-downs and low capacity utilization.

As far as the steel industry is concerned, the available data shows that electricity consumption increased from 468 kWh/tonne of ingot steel in 1980/81 to nearly 500 kWh/tonne in 1984/85, but declined to 470 kWh/tonne in 1988/89.

3.6 Indigenization Effort

The Indian power industry has also been indigenized to a considerable extent. In addition to the introduction of 210 MW and 500 MW coal-fired thermal power stations in the last ten years or so, the transmission system has also been upgraded with the introduction of 220 kV and 400 kV lines. These are all manufactured in India now. Further upgradation to the 750 kV level and the introduction of high-voltage-DC(HVDC) transmission systems are on the anvil.

At present, despite the resource crunch of the SEBs, and the general "capital-constraint" situation of the Indian economy, financial assistance from overseas (largely multilateral/bilateral assistance) is less than 10% of total power sector investments in India. In fact, as far as central sector projects are concerned financial assistance from overseas was about 10% to 11% of their total investments in the Seventh plan period (1985/86-1989/90), and in the state sector, the share was much less (about 8% or so).

It may be noted that about 40% of the total power sector investment during the Seventh FYP period was in the central sector.

The share of multilateral/bilateral assistance to the Central sector corporations is relatively high largely because their financial position is better than the state/UT utilities -- and it is perceived that they will be able to meet their debt-service obligations relatively more easily.

However, there are significant differences from project to project. Certain power projects with multilateral assistance have also used indigenous equipment.

IV. Tariffs and Financial Issues

The SEBs financial operations are regulated by the Electricity (Supply) Act of 1948, which is amended periodically to reflect changes in the environment of the subsector. While SEBs set tariffs within each state, they consult their respective state Governments when fixing or raising tariffs. Thus, tariffs generally represent a compromise between the financial objectives of the SEB and the state Government, and the structure is determined by socio-political criteria, especially the perceived ability of different consumers groups to pay.

The Electricity (Supply) Act of 1948 stipulated that tariffs assessed by the SEBs should meet all operating costs and capital charges, and earn a rate of return as specified by the state Governments. Despite this, no state Government imposes a mandatory rate of return on the SEBs. Rather, the emphasis was and is on providing power for industrial and agricultural development at reasonable rates. The agricultural sector and the the low income group domestic consumers are heavily subsidized in most of the utilities. To encourage industrial development, certain states also offer low rates to large industries. As a result, many SEBs incur heavy financial losses and are unable to generate sufficient resources to finance the additional investments required by the increased growth rates in the demand for energy. Power shortages are therefore common. To improve the financial operations of the SEBs, an amendment to the Electricity (Supply) Act was introduced in April 1985, which requires all SEBs to earn a minimum 3 per cent return on their net

fixed assets as at the beginning of the year, after meeting all expenses, with interest during construction capitalized. However, because most SEBs still do not reach that level, efficient operations and investment continue to be constrained by limited resource mobility.

4.1 Tariffs

Most SEBs and other utilities distinguish between high tension (HT) and low tension (LT) consumers. The LT consumers are subject to an energy charge, and the HT consumers a two-part tariff with a demand charge and an energy charge. The demand charge is based either on the maximum demand registered during the billing period/month (e.g., Tamil Nadu Electricity Board and Andhra Pradesh Electricity Board) or on the contracted monthly demand (e.g., Haryana State Electricity Board). The HT supply is availed of mostly by industrial and commercial groups and for railway traction purposes. The rates charged to commercial consumers are normally higher than those for industrial consumers although some Government departments, educational institutions and hospitals are charged concessional rates. Concessional rates are also offered by some SEBs to new industries or industries established in less developed areas. For instance, the Gujarat Electricity Board (GEB) levies an increasing block structure for both the demand and energy charges, while most other utilities assess a single rate for demand charge. The energy charge, in some cases, is assessed on a decreasing block structure. In earlier years, most of the utilities had promotional tariffs but

these are being gradually revised to perform a regulatory role.

In many SEBs, the rates charged to LT commercial and industrial consumers are among the highest. The domestic tariffs are based on an increasing block structure in many SEBs (e.g., Gujarat, Delhi, Andhra Pradesh), while others have a single energy charge. Consumption for the very low income groups (urban and rural) is normally subsidized and consumption for the agricultural sector is heavily subsidized in almost all states. The agricultural tariffs are mostly flat rates based on the connected load and payment may be on an annual or biannual basis.

The fuel adjustment clause is introduced in the tariff schedules of some SEBs. Electricity duties are also imposed by many state Governments. Seasonal tariffs are offered by the SEBs of Gujarat and Punjab. The GEB introduced time-of-use tariffs; TNEB is experimenting with time-of-use rates for large industrial consumers. None of India's utilities have interruptible tariffs. The Central Sector power corporations (e.g., NTPC, NLC) sell power to the SEBs at mutually agreed rates.

Tariff structures and levels in nearly all states need to be rationalized for more efficient performance by the power sector. For example, one impact of the present tariff structures is to move diesel consumption from isolated rural areas (where diesel pumps are being replaced by electrical pumpsets) to industrial consumers who are obliged to install captive generators because of power shortages. Also, rather than adjusting tariffs to meet a utility's financial viability or national economic efficiency,

social goals and equity considerations have guided most tariff policies and revisions. Though these social goals are important, a more equitable trade-off between the objectives could be achieved.

The SEBs do charge some consumers categories a rate below the cost of supply. These categories include the agriculture sector, the domestic consumers, public lighting, water supply and seweage works, and in some cases, the LT industry category and bulk consumers as well. The agriculture sector is by and large the most highly subsidized sector.

4.1.1 Agriculture Sector

On an all-India basis, the share of sales to this sector has increased from 17.6 per cent in 1980-81 to 23.4 per cent in 1987-88. While states such as Kerala, MP, Orissa and HP have low agricultural sales (less than 10 per cent), other states such as Punjab, Haryana, UP, Karnataka and Gujarat have a higher share of sales to this sector (greater than 30 per cent). However, during the irrigation season, the share may be as high as 50-60 per cent (e.g. Punjab, Haryana, parts of UP etc.). It must be mentioned that this sector contributes relatively less to the total revenues realized (in 1987-88, 12 per cent in Punjab, 15 per cent in Haryana, 5 per cent in Karnataka and 12 per cent in UP).

Agricultural loads are widely scattered and have low load factors (usually 6-12 per cent). This imposes a heavy burden on the utilities for they have to plan for additional capacity for loads with low load factors, which draw power only during the

irrigation season, as well as incur high line (energy) losses a consequently incur higher financial losses.

Most SEBs now have flat rate tariffs for this secto Meters which were installed earlier have been dismantled. Th creates problems for measuring agricultural consumption and the is no reliable data pertaining to consumption in this secto Further, small industries such as flour mills continue to r under the name of agricultural connections. It is important keep these facts in view while discussing agricultural tariffs a consumption levels.

In 1987-88, the average revenue realized from this catego varied from 8 paise/kWh in Maharashtra to 22 paise/kWh in Gujara and 32 paise/kWh in Himachal Pradesh. In 1988/89, the average revenue realized from agricultural consumers in TNEB was 10. paise/kWh, and in WBSEB was 26.8 paise/kWh. This low rate often stated to be an assistance to this important sector, wh contributes about 40 per cent to the national income. There m be justification for such subsidized inputs in the sectors agriculture and food production; but there is no justification making the SEBs subsidize this sector.

The SEBs see clearly the need for effecting increases in t agriculture rates (at least to wipe out the deficits), but certa socio-politico-economic factors which are beyond their contr over-ride their financial viability considerations. At presen the state Governments are supposed to subsidize the loss incurred in agricultural sales. However, actual practice is ve

different. Many state Governments do not give any subsidy at all; in a few cases, even where provided, the actual cash flow does not take place. In some states, there are disputes as to the correctness of the claim made by SEBs. In some of the SEBs, even the subsidy is not enough to enable the SEB to have a surplus. The subsidy due is over 25 per cent of the total income of the SEBs of UP, Punjab, and Tamil Nadu; more than 10 per cent for the SEBs of Bihar and Gujarat; and less than 10 per cent for AP, Kerala, Rajasthan, Orissa and West Bengal. For all the SEBs, the subsidy actually received has always fallen short of the subsidy required to enable them to earn a 3 per cent surplus. As these amounts are very large for many SEBs, non-payment of subsidy leads to a resource crunch not only for implementation of projects but even for day to day commercial operations. The ability of the SEBs to meet their commercial obligations is therefore predicated on the fortunes of the state budget.

4.1.2 Domestic and Commercial Sectors

The average revenue realized from sales to the domestic sector continues to be below cost. Typically, domestic consumption constitutes 10-15 per cent of the total, whereas it realizes only 8-12 per cent of revenues. This imbalance should be reviewed taking note of the fact that it is the urban elite who consume large amounts of power. The whole issue needs to be examined in the context of increase in urbanization, use of electricity consumes appliances, rural-urban migration, changing income distribution scenario, etc.

The quantum of subsidy to domestic consumers with respect to the pooled cost of supply is less than Rs.5 crores for Himachal Pradesh and Rajasthan; between Rs.10-20 crores for Andhra Pradesh and Kerala; and greater than Rs.20 crores for Bihar, Gujarat, Haryana, Madhya Pradesh, Maharashtra, Tamil Nadu and Uttar Pradesh. Punjab is the exception, where the domestic consumers are charged at rates higher than the pooled cost of supply.

It is important to note that in most small towns, the cost of supply is much higher than the pooled cost; and the losses are therefore higher. This aspect is not taken into account while fixing tariffs. Furthermore, in some states, a lower rate for the non-metropolitan areas or for hilly areas is in force.

Inverted block rates can be effectively used for generating additional revenue from customers who can pay. For instance, in the WBSEB system, the inverted block tariff is in force. For the first 50 kWh consumed per month, the tariff rate is 52 paise/kWh; for the next 50 kWh, it is 60 paise/kWh, for the next 700 kWh, it is 70 paise/kWh; and beyond that it is 100 paise/kWh. In TNEB however, there is no inverted block tariff. In fact, except for two or three SEBs, the others charge only an average energy rate for the domestic category. Some SEBs have expressed operational difficulties in implementing inverted block rates, but these problems are not unsolvable and the issue of inverted block deserves serious consideration.

The LT commercial consumers continue to pay rates higher than average revenues realized in all SEBs. In several SEBs, the

average revenue realized from this category is even higher than that realized from industry (HP, AP, Punjab, Karnataka and Tamil Nadu). Furthermore, an analysis of tariffs in some SEBs indicates that the LT commercial rates are even higher than the HT industrial rates. In 1987-88, the average for the LT commercial sector have been the lowest in Haryana (82 paise/kWh), and highest in Karnataka (183 paise/kWh); the typical average rates for the other states being in the range of 90-110 paise/kWh. This sector, while accounting for only 2-4 per cent of the energy consumed typically, provides 5-8 per cent of the revenues for the SEBs.

It is observed that data pertaining to consumption in the commercial sector refers largely to LT consumers, and it is likely that the HT commercial consumption (which is charged at higher than industry rate) is merged with HT industrial consumption.

4.1.3 Industries Sector

In 1988-89, the average revenue realized by TNEB from all HT and LT industries was about 90 paise/KWh, and by WBSEB was 117.8 paise/kWh. And in 1987-88, the average revenue realized varied from 73 paise/kWh (in HP and Punjab) to 117 paise/kWh (in Bihar). In all the SEBs, the average revenue realized from the entire industry sector is higher than the average revenue realized from all consumer categories. However, it must be emphasized that while the LT industry accounts for 4-8 per cent of the total energy sales, the HT industry accounts for 35-45 per cent of the total energy sold and hence the average rates for the entire industrial sector would be closer to that for HT industry.

4.2 Composition of Costs

The components of the total cost of utility operations are broken down into: (a) power purchases; (b) power generation; (c) employees cost; (d) establishment cost; (e) repairs and maintenance costs; (f) depreciation; and (g) interest and finance charges. The contribution of repairs and maintenance costs is usually 1% to 4% of the total costs.

4.2.1 Power Purchases

With the increasing role played by the central sector in power generation, the share of power purchased by state sector utilities has in general, increased over the years. There has been a significant increase in power purchases in Andhra Pradesh (AP), Himachal Pradesh (HP), Karnataka, Kerala, Punjab, Rajasthan, Tamil Nadu (TN) and West Bengal (WB).

From 1985/86 to 1988/89, the share of cost of power purchases increased from 9.1% to 34% in WBSEB, while it remained at the 23% to 25% level in TNEB. In 1987-88, the share of power purchased in the total cost was highest in Karnataka (62%) and the lowest in Punjab (6.5%).

4.2.2 Power Generation

The cost of generation of power in a particular state is a consequence of the hydro-thermal mix in that state. In states such as HP and Kerala, which depend on hydro for their needs, the share of power generation cost of total operating cost is low. In states such as Maharashtra, 38% of the operating costs are

accounted for by generation. Similarly, in Bihar, Haryana, Punjab, Uttar Pradesh (UP), Madhya Pradesh (MP), TN and AP, power generation costs account for over 25% of the total operating cost. In 1988/89, power generation accounted for 31% of TNEB's operating costs and about 20% of WBSEB's costs.

It is not possible to make a direct comparison of the fuel costs across the SEBs, owing to differences in cost of coal haulage. However, it is interesting to note that in 1987/88, the fuel cost for Haryana was 57.1 paise/kWh while that for Punjab 39 paise/kWh, although the coal haulage distance for the two states is not vastly different.

4.2.3 Employee and Establishment Cost

This includes the employee costs as well as administration and general expenses. The most notable feature of this head of account is that it has decreased in several states (Haryana, Karnataka, TN, WB etc.) since the mid-1980s. In Tamil Nadu, it reduced from 23 to 22% during the 1985/86 to 1988/89 period; and in West Bengal it reduced from 23 to 19%. Typically, the share of this head is about 20 per cent to 23 per cent. Kerala is perhaps the only state where the share of this head touched the 44% level in 1986-87.

A related issue is that of workforce productivity. Although it is not possible to compare the manpower employed per kWh sold across the utilities (for some utilities supply power in bulk to distribution agencies, while other distribute power directly;

moreover, the share of exports and imports to total sales of different utilities varies greatly), a time-series trend of this ratio would be a useful indicator. In fact, both for TNEB and WBSEB, the work force productivity seems to have increased in the past decade or so.

4.2.4 Depreciation and Interest and Finance Charges

While the interest and finance charges component has remained at about 15% to 20% in several states, it accounts for over 30% for Haryana, Punjab and HP. As against this, the share of depreciation is around 4% to 6% in the total operating cost; the highest being in MP and AP (9%) and the lowest in HP (2%).

4.3 Investment Financing

The present system of investment financing for public enterprises integrates their plans fully into the total public sector plan. Financing of the power sector projects is hence linked to the overall plan resources and allocation procedures.

The sources of investment funds for SEBs comprise State Government loans, loans from financial institutions, open market borrowings, internal resources and Central assistance. The open market borrowings of SEBs are governed by Planning Commission and State Government decisions and these are fully guaranteed by the respective State Governments. The State Government loans and the institutional loans available to SEBs are again decided by the respective State Governments. Some of the aspects and consequences of this system of investment financing are discussed

below.

The internal resources generated by the public enterprises are a part of overall plan resources. However, the outlay provides for a planned investment programme irrespective of the level of internal resources generated by the public enterprise. During the Sixth FYP period (1980/81 to 1984/85) about 16.8% of the public sector outlay was financed by the contribution of public enterprises. During the Seventh FYP period (1985/86 to 1989/90), this contribution was about 19.7%.

The SEBs were expected to incur net losses to the tune of Rs.15.69 billion, during the Seventh FYP period, after raising an additional Rs.60 billion. The outlay for their investments was about Rs.226.87 billion. The quantum of extra-budgetary resources is limited in the case of SEBs, unlike the central sector corporations which are able to mobilize more resources. Thus, bulk of the investment financing in the power sector (especially the state sector) is through the budget. Such heavy dependence on budgetary resources leaves the SEBs with very little financial autonomy in planning for and mobilizing their investment funds.

4.4 Financing Pattern and Financing Terms

There are significant differences in the pattern in which the capital expenditure and revenue deficits of the various SEBs are financed. The finances are through, among other sources, commercial borrowings, institutional loans and state Government loans.

The interest rates for institutional loans are the highest, ranging between 8% and 12%, while the state Government loans carry the lowest interest rates. However, there are considerable differences in the rates charged by state Governments to different SEBs. The weighted average interest rates vary from about 3.13% in the case of GEB to 11.72% for Haryana SEB (1987-88). In the case of institutional loans, the rates do not vary much across the SEBs. As expected, the weighted average rates for all the types of loans show an increasing trend.

Once a project is included in the plan, there is a virtual guarantee of funds to cover costs irrespective of any time overruns or cost overruns that it may suffer. However, there is a considerable uncertainty regarding the amount of funds that would "actually" be made available to the power projects, especially the ones in the state sector during the different years of the plan (this is in fact a major factor contributing to cost escalations and delays in projects). The reason is that the yearwise allocation of funds made at the beginning of a plan period is quite tentative and the actual allocation gets considerably modified in every annual plan. Whenever there is an overall resources crunch or the actual resource mobilization does not match the estimated figure, the allocations made to the power sector and the allocations made to different projects within the power sector are considerably modified. In such situations, on-going projects or projects nearing completion normally receive priority. Thus, the SEBs have assurance of the investment funds available to them only on an annual basis.

This non-availability of assured investment funds over a long-range planning term forces SEBs to carry out their investment programmes in an ad-hoc manner based on short-term considerations. In order to circumvent this problem, the SEBs try to include many new schemes in each plan period, by deliberately under-estimating their investment costs. The idea is that once a project is included in the plan, it would be seen through, whatever the cost escalations or delays in commissioning. Moreover, the new schemes in each plan would become on-going schemes in subsequent plans and would receive priority in the allocation of the limited resources. This results in spreading rather thinly the limited resources available over many projects. Hence, further delays and cost escalations occur.

As far as the thermal power projects are concerned the cost overruns are generally of the order of 60-100 per cent, with some exceptions. The percentage time overruns for thermal projects are very similar. For hydro power projects, although we were not able to obtain reliable information on time overruns, we do have estimates of percentage cost overruns. From these we cannot reach any definite conclusions regarding the range of cost overruns, but it is evident that the percentage cost overruns of hydro projects is higher than those of thermal projects. The main reason for this is the fact that the implementation of hydro projects depends upon the conditions at the site i.e. these are site-specific. On the other hand, thermal projects are more or less independent of site conditions and have a generalised design.

As a short-term measure to manage this crisis, the Power Finance Corporation (PFC) was established in July 1986. The PFC raises extra budgetary resources and finances generation, transmission and distribution projects, renovation/modernization projects, system improvement and energy conservation projects. It also stipulates certain conditions on the financial position of SEBs so that they can meet their debt-service obligations.

There is, however, an urgent need to undertake some long-term measures in order to have the investment programmes in the power sector executed more efficiently. The SEBs would also have to improve their financial performance and raise their internal resources. It would be useful if the SEBs prepared comprehensive corporate plans as well as detailed project reports for their individual projects, giving a more or less accurate programme of yearwise investments required. All the investment finances (budgetary and extra budgetary) made available to the power projects could be channelized through a single body, which would analyze the corporate plans and detailed project reports, and make provisions for investment programmes on a committed basis over a long-term (say 5 years, to coincide with Plans). This body could at the same time stipulate certain conditions for the financial viability and internal resource generation of the power utilities as a prerequisite for receiving investment funds.

V. TERRITORIAL COVERAGE

In addition to electric power being viewed as a prime-mover of economic growth and its demand as a consequence of economic growth, electricity is also viewed as a service that will improve the quality of life of the peoples of India. It is this perspective which has mainly lead to a situation where electricity tariffs to certain consumer categories are below even the variable operating costs. However, despite the financial problems this has resulted in, the expansion of the supply coverage goes on.

All urban cities and towns are electrified except for slums. The role of rural electrification is of particular relevance here.

Both the central and the state/union territory Governments give high priority to rural electrification (RE) programs in India. The primary objective is to stabilize agriculture and ensure increased agricultural output by providing low priced (but nevertheless costly) power for irrgation pumps, involving mostly ground water pumping by individual farmers. A secondary objective is to provide electricity for domestic, commercial and small industrial consumers and for street lighting in the villages, thereby improving employment opportunites and the quality of life in the rural areas. The RE programmes are financed directly by the state Governments and the Rural Electrification Corporation (REC). Each SEB prepares, along with a generation and transmission program, a distribution and rural electrification programme for each Five-Year Plan. This programme is developed on the basis of targets for extending electricity to villages and

number of pumpsets. Simultaneously, the Planning Commission prepares a five-year expenditure plan for RE on a nationwide basis. The two approaches are then reconciled in discussions between the state, REC and the Planning Commission, and annual programs and allocations are formulated for each state.

While the REC concentrated initially on extending feeders to the rural areas and on energizing pumpsets, its focus now covers a wider spectrum, including providing electricity to rural areas such as hill, tribal and desert regions. When inadequate investment creates weaknesses in the sub-transmission networks, REC finances the supporting networks to further RE programs. The REC also provides technical assistance to SEBs in the following areas: (i) planning and designing rural networks; (ii) promoting energy conservation by improving existing networks, rectifying pumpsets and adopting energy efficiency criteria in all RE activities; and (iii) training of personnel for RE projects.

The SEBs establish the priorities for their state RE programme based on the local backlog of potential consumers' applications for connections, ease of grid extensions and the revenue potential of each area. Planning RE programs and coordinating them with projects of other agencies involved in rural development is conducted at several levels within each state, with the most effective coordination occuring at the district level.

The total number of villages electrified throughout the country increased form 3,061 in 1950/51 (0.54% of the villages in existence at that time) to about 460,000 by the end of January 1990 (79% of the existing villages).

The performance of individual SEBs in providing RE varies widely. The states of Punjab, Haryana, Kerala and Tamil Nadu and the union territories of Chandigarh, Delhi, Pondicherry, Lakshadweep and Dadra and Nagar Haveli achieved 100% rural electrication by the end of 1986/87, while the states of Bihar, Orissa and West Bengal did not achieve such high implementation records. At the regional level, the Southern region achieved 92% RE at the end of 1985/86, while the Western region achieved only 52%. The total number of pumpsets energized in the country at the end of January 1988 was 7.05 million, with Maharashtra registering the highest number (1.21 miliion), followed by Tamil Nadu with 1.16 million. Electricity consumption for agricultural purposes (irrigation mainly) accounted for about 24% of the total sales in the country during 1986/87. These consumers also receive power at highly subsidized rates.

Under the Government's Minimum Needs Programme (MNP), all Northeastern hill states and union territories, as well as districts in states with less than 65% electrification and all areas included in the Tribal SubPlan have been identified as priority areas for RE. Adequate funds are being provided for the MNP at relatively soft terms compared to the normal RE programme.

However, it must be mentioned that despite the high rate of rural electrification, very few rural households are in fact electrified. The reason is mainly that the small or landless farmers, or other rural dwellers, are not in a position to pay even the service connection charges. Moreover, several rural poor normally have thatched huts, and it is not safe to extend a live-electricial wire there. Therefore, RE programmes have until now benefited largely the relatively well-to-do rural dwellers only.

In addition, it may be noted that the quality of power supply is very poor. In several states, power supply to rural areas is rostered i.e. available only a few hours each day in rotation (as notified by the concerned utility in advance). Moreover, even when power is supplied, the voltage levels may be very poor (it is known that several 11 kV feeders have been extended to over 20-30 km for meeting RE targets). Further, in the event of any breakdown in the transmission line or local substation, it takes several days to get the fault rectified.

Therefore, it is evident that although over 80% of the geographical area of the country may be having access to electricity, the quality and reliability of power supply leave much to be desired -- and there is substantial scope for increasing the consumption in rural areas.

VI. ENVIRONMENTAL IMPACTS

Issues relating to the environment have assumed importance in the last decade, particularly with the threat of global warming. The Ministry of Environment and Forests, in the Government of India, is responsibile for identifying strategies to contain environmental damages. To this extent, all power stations (as do other sectors of the economy) have to submit environmental impact statements to obtain clearance for any power projects. These statements give information on the steps taken to maintain emissions levels in the case of thermal and nuclear stations, and regarding protection of the environment and resettlement and rehabilitation of the population in the catchment areas for hydro power stations. Even the transmission programs have to take clearance regarding right of way through forests etc. Inspite of the steps taken by the ministry, the utilities have not really realized the seriousness of the problem. The chapters containing steps for controlling emissions are quite sketchy and power projects get delayed for reasons of not providing enough data in this important area. Large hydro projects have of late attracted the attention of environmental groups who have (rightly or wrongly) taken the issue of environmental damage by large hydro power projects beyond proportions. In the entire process, the only thing that happens is that the project gets delayed by several years and leads to cost overruns as well.

The Central Air Pollution Board (CAPB) is responsible for setting and enforcing air and water quality standards. Although the CAPB has its offices in several states, their success towards

enforcing the standards has been limited. Thermal capacity presently accounts for about 68% of the total utility installed and 73% of the energy generation. The power sector presently accounts for about 50% of all the emissions responsible for global warming in India. This includes CO_2, CO, CH_4, and NOx emissions. Among the various emissions released by combustion, carbon dioxide emissions are considered to be most critical. The power sector accounts for over 96% of the total carbon dioxide emissions in the economy. There are standards for emissions of CO_2, SOx and NOx.

Electrostatic precipitators (ESPs) have been installed in almost all the new power stations. Although there have been some problems regarding the operations of ESPs, their performance by and large has been satisfactory. The Bureau of Indian Standards (BIS), in close cooperation with the concerned ministries, is in the process of bringing out the necessary standards.

6.1 Pollutant Emissions and their Impacts

Estimates of emission levels are presented for a coal-fired thermal power station -- which account for more than 60% of total utility capacity. These estimates pertain to a 210 MW representative plant burning North Karanpura coal with the gross calorific value (GCV) of 3772 kcal/kg, and containing 40% ash. The plant is equipped with an electrostatic precipitator for particulate emission control (99.8% efficiency), and a wet mechanical draft cooling tower. Onsite solid-waste disposal and water treatment or recirculation to minimize discharge are assumed, along with a PLF of 61%. Estimates of air and water

emissions for the representative plant are based on control levels required by current Central Pollution Control Board (CPCB) standards which are listed in Tables I and II, respectively.

Table I : Indian Air Quality Standards

A. Ambient Standards

Area Classification	8 hr average concentration ug/m³ not to be exceeded 95% of the time in a year		
	(TSP)	(NOx)	(SO_2)
Industrial and mixed use	350	120	120
Residential and/or rural	200	80	80
Sensitive or protected	100	30	30

B. Standards for Particulate Emissions (mg/m^3)

Boiler Size (MW)	Vintage: Old plants (pre 1979)	Vintage: New plants
<200	600	350*
>200	----	150

* 150 for protected areas

Table II: Minimal National Standards for Wastewater from Thermal Power Plants

National Standards for Condenser Cooling Waters (Once-through cooling systems)

Parameters	Maximum Limiting Concentration
pH	6.5 - 8.5
	Not more than 5°C higher than the intake water temperature
Free available chlorine	0.5 mg/litre

National Standards for Boiler Blowdowns

Parameters	Maximum Limiting Concentration (mg/litre)
Suspended solids	100.0
Oil and grease	20.0
Copper (total)	1.0
Iron (total)	1.0

National Standards for Cooling Tower Blowdown

Parameters	Maximum Limiting Concentration (mg/litre)
Free available chlorine	0.5
Zinc	1.0
Chromium (total)	0.2
Phosphate	5.0
Other corrosion inhibiting materials	Limits to be established on case by case basis

National Standards for Ash Pond Effluents

Parameters	Maximum Limiting Concentration (mg/litre)
pH	6.5 - 8.5 preferably greater than 7.0
Suspended solids	100
Oil and grease	20
No limits for heavy metals at present	

Carbon Doxide Emissions

For every million kcals released by the combustion of coal, 385 kgs of carbon dioxide is emitted. The total amount of carbon dioxide released to the atmosphere from the 210 MW representative plant is 1.03 million tonnes/yr.

In recent years, concern has grown over the possibility of climatic changes brought about by increasing carbon dioxide levels in the atmosphere because of its absorption of infrared radiation from the earth. High levels of carbon dioxide in the earth's atmoshpere may therefore, produce a "greenhouse effect", thus increasing the global temperature. It is significant to note that increases in global temperature due to CO_2 emissions (over the period of a human lifespan) are now approaching rates of change generally observed over geologial timespans. Global warming due to coal combustion is a contentious issue: that it will occur is inevitable - the arguments are about rates of change and appropriate responses. This one particular emission alone has the potential to restrict or even ultimately ban coal combustion for power generation as technological fixes are prohibitively expensive and result in producing more solid or liquid waste.

Sulphur Dioxide Emissions

When coal is burnt, the sulphur is converted to sulphur dioxide. The sulphur dioxide escapes into the atmosphere and is either deposited locally or is slowly (and over great distances) converted to sulphuric acid or sulphate. The possible impacts of sulphur dioxide emissions include human health effects, crop and

forest damage, acid rain, metal corrosion, and visibility degradation (haze). However, as the sulphur content of Indian coals is very low, the control of sulphur dioxide emissions does not merit high priority.

Nitrogen Oxide Emissions

Nitrogen oxides are released from the boiler stack when coal is burnt. They are produced by the oxidation of atmospheric nitrogen during combustion, and to a much lesser extent by the oxidation of nitrogenous compounds in coal.

The environmentally important species of nitrogen oxides are nitric oxide and nitrogen dioxide. The species most commonly found in the atmosphere is nitrogen dioxide, which may contribute to human health problems. Nitrogen oxides can also lead to damage of agricultural crops and forests, as well as cause acid rain. At current levels however, nitrogen dioxide is not considered a threat to ecosystems.

Atmospheric Emissions of Solid Particles (Particulates)

Particles formed during coal combustion usually vary in size from 0.01 to 10 micrometre in diameter. While large particles are efficiently removed by the emission control system, particles less than a few micrometres in diameter are difficult to capture. These small particles, many in the range of 0.1 to 1.0 micrometre, are easily respirable and may have adverse effect on human health.

Particles less than 0.01 micrometre in diameter are not usually deposited in the respiratory systems; those with a diameter of 0.01 to 3 micrometre may be deposited in the alveoli of the pulmonary region; those larger than 1 micrometre tend to be deposited in the nasopharyageal and tracheobronchial regions. These particles remain in the respiratory system for 2 to 6 weeks. Since the particles also absorb sulphur, trace elements, and polynuclear aromatic hydrocarbons, they can potentially magnify the effects of these substances by holding them in the lungs. Further research is needed on the effect of the two latter substances on the lungs as they have been identified as carcinogens.

Impacts of Solids Disposed on Land

The solid-waste products of coal combustion -- fly ash and bottom ash -- pose major waste disposal problems, because the ash content of Indian coals is high. In addition, scrubber sludge may also be there, if flue gas desulphurization process is used.

Ash disposal involves potential problems of pollution of surface and subsurface water. Typically, fly ash from the combustion of Indian coals consists of fine sand, silt and clay. Chemically, more than 90% is oxides of aluminium and silicon, and trace amounts of toxic elements (Arsenic, Cadmium etc.) are also present. Mineralogically, they contain mullite, magnetite, hematite, quartz and an appreciable amount of glass. Approximately 2% to 5% of fly ash is soluble in water; the solutions exhibit a wide range of pH values. Acidic leachates,

containing sulphates, iron, zinc, lead, cadmium, and manganese, are often carried over into natural water bodies and result in contamination of both surface and ground waters.

Ash disposal presents some environmental problems, but they are relatively minor and easily controlled. Major problems are faced in the disposal of FGD scrubber, which is composed primarily of calcium sulfite hydrates -- which require larger amounts of land for ponding. Chemical treatment, however, can change the properties of sludge, making possible its disposal by landfill. Also, FGD systems can be operated in the forced-oxidation mode, producing a sulphate sludge that is more easily dewatered than sulphite sludge.

Wastewater Discharge

Wastewater discharges from coal-fired power plants can cause water-quality impacts that have adverse effects on aquatic ecosystems. However, the water pollution problems associated with direct discharge of wastewater are of less environental concern than other issues discussed above.

The large quantity of water used in once-through systems is not normally treated. Intermittent chemical treatment, however, is often necessary to control the growth of algae or slime on condenser surfaces. Chlorine added for this purpose may react with organics to form chlorinated phenols and hydrocarbons, which are important pollutants. Residual chlorine reacts with ammonia naturally found in receiving waters to form chloromines. Chloromines present the most common chemical threat to fish and

the lower phyla; the effects of these substances, however, have not been thoroughly studied.

Recirculating cooling systems produce cooling primarily by evaporating a portion of the water. Dissolved, non-volatile impurities and contaminants entering the system with make-up water are therefore concentrated, and a blowdown stream must be withdrawn to prevent their build-up. Scale deposits are prevented by chemical additives, which ultimately enter the blowdown. These include inorganic phosphates, polyelectrolyte antiprecipitants, and organic-polymer dispersants.

Pollutants present in dry ash may dissolve in the sluicing water. The normal method of ash disposal in India is to transport it in slurry form to lowlying, barren areas in the vicinity of the plant. The overflow from the ash pond is discharged into a surface water body. The USEPA has determined that priority inorganic pollutants (excluding asbestos and cyanide) in fly-ash and bottom-ash ponds warrant further concern. These pollutants can enter groundwater or surface waters and may be ingested by aquatic organisms or may contaminate crops irrigated with that water.

Thermal Pollution of Water

Coal-fired power plants using once through cooling systems release waste heat into water systems. Temperature rises in the receiving water have centered at about 10°C on the average. However, the CPCB requirement of maximum recovery body temperature not to exceed 40°C implies that future rise will be less than 5°C. Organisms may become acclimatized to higher water temperatures, which means that both the upper and lower lethal temperatures for the organisms get raised. Fluctuations in effluent temperature may cause more stress for aquatic life than constant high temperatures. If a plant is shut down or a thermal plume is displaced, acclamatized fish may die. The elevated temperatures may alter the physical environment, and these changes will in turn alter the life functions of aquatic organisms. Changes may occur in such properties as salinity and dissolved oxygen.

Other impacts on organisms of increased water temperatures include elevated metabolic rates (which influence oxygen demand) and higher total energy needs. Effects may also include elimination of food sources, inability of organisms to catch available food, lowering of reproductive potential, and increased susceptibility to disease.

Land Use Impacts

Although there is no strong correlation between power-plant capacity and land requirements, some relationship does exist. For plants with total installed capacity in the 1000 MW range, typical

site sizes are about 160-200 hectares. Sludge disposed-of in ponds represents a long-term commitment of the land. Ponding of untreated sludge, and perhaps even of some sludge that has been treated, prevents future development of the site. The solid-waste disposal area for a 210 MW plant may be approximately 80 hectares. Accordingly, 320 hectares is a typical site size requirement for a 4 x 210 MW station when the lifetime waste disposal issue is considered. In addition, about 40 hectares of land is needed for the township to house the operating personnel.

6.2 Directions for the Future

The Government of India has constituted a Working Group and several sub-groups to identify the various options that would go towards working out strategies to contain the damage to the environment from the power sector. The options fall into two broad classes:

(a) Technology options, which would lead to increased efficiency in the entire power generation and consumption cycle; and

(b) fiscal and pricing options.

The first option would also include substitution possibilities such as renewable options which are environmentally more benign as compared to conventional power generation options. It must be mentioned that the two options are linked very closely as it is ultimately costs and prices that would decide the direction which would be taken; e.g. some of the renewable options are likely to compare favourably with thermal power, if the government were to add elements of subsidy to renewables or tax

the conventional power sources. Hence it is important to carry out an economic evaluation at the first stage and then adjust these cost and prices with subsidies and/or taxes in order to indicate the direction towards which the economy would have to move. Some of the options are discussed below.

Increasing efficiency in power generation

The average gross conversion efficiency for thermal generation is 28%, and the average net efficiency is about 25%. More than 70% of the installed capacity in thermal stations operates at efficiencies below 30%, and 25% of capacity operates at efficiencies below even 25%. Currently, operating efficiencies are close to 35% in several countries. Enhancing power station performance to increase operating efficiency would increase their power output (at the same coal input rate) by nearly 15%, implying that CO_2 emissions per kWh generated would decrease by nearly 12%.

Auxiliaries in thermal power stations consume about 10% to 12% of the installed capacity. It is possible to reduce the auxiliary consumption by adoption of energy efficient accessories, in order that this is reduced to about 8%. Decrease in in-plant consumption would, therefore, also result in a reduction in CO_2 emission (kg of carbon dioxide per kWh delivered at station busbar).

Coal supplied to a power station is largely from open-cast mines and has a lot of non-coal material (principally shale and rock) mixed with it. Washing this coal before it is supplied to

power stations would greatly reduce the non-coal matter that travels with it. Boiler efficiency with washed coal rises to about 89.5% and in-house electricity consumption reduces from 10% to 8% of gross generation.

Increased use of natural gas for power generation

Substitution of coal by gas to the extent possible would also reduce CO_2 emissions. Current plans for gas-based capacity is for an addition of 7745 MW during 1990-95. Additions during 1995-2000 would probably be about 10,000 MW.

Apart from these plans, all the gas presently flared off the West coast could be utilized for power generation in West India which would reduce the need for coal. Currently, over 2.5 billion cu.m of natural gas are flared in the Bombay High basin annually. This gas could generate about 12000 GWh of electricity which implies an installed capacity of about 2200 MW of gas-based combined cycle TPS, or an equivalent 2,500 MW coal-based TPS using 8.5 million tonnes of coal per year. This is a strategy that needs a closer look.

Transmission and Distribution

T&D losses in the Indian power system are estimated at 22%. However, owing to the practice followed by some SEBs of diverting a certain portion of non-technical/commercial losses towards unmetered power supply to agricultural consumers, the actual T&D losses may be somewhat higher.

The Committee on Power[1] recommended a somewhat realistic target of reducing T&D losses to a level of about 15% by the year 2000. Of course, little has been done in this direction so far. In fact, per cent T&D losses increased until the mid-1980s, from 17.5% in 1970-71 to 21.5% in 1987-88, and have remained fairly stable since then.

Analysis shows that losses at the transmission level are quite under control at about 4.5% to 5.5% and it is the losses at 11 kV and lower voltage levels that are to be checked. These also include non-technical losses, arising from under-recording in meters (most mechanical meters tend to slow down with age), meter tampering, defective meters, and pilferage etc. Losses arising from the latter three factors may be reduced with more care in testing and replacement of meters in time, and strict enforcement of laws to ensure that meters do not get tampered and that electricity theft does not take place. Also, a coordinated program of periodic meter-testing and recaliaberation needs to be introduced. It is understood that some utilities have established meter-testing laborataries, but their achievements and performance levels need to be upgraded.

Further, to reduce commercial losses, bills must be issued in time, collected in time and energy theft must be regarded as a cognizable offense and serious steps must be taken against it. Technical losses can be reduced by system improvement, conversion of LT lines to HT lines, improvement of power factor etc.

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1) Report of the Committee on Power, Planning Commission, Government of India, New Delhi, 1980.

It is very clear that the T&D system needs to be strengthened. A mere 1% reduction in T&D losses could generate resources enough to meet 2% to 3% of annual plan outlays of the SEBs. A system of energy auditing must be propogated, so that it is possible to asses the technical and commercial losses separately and then to take steps to minimize them.

Table 1 : TNEB -- Thermal Efficiency

Year	Coal ('000 tonnes)	F.O. (KL)*	LDO (KL)#	LSHS (KL)@	Generation (GWh)	Heat Rate (kCal/kWh)
75/76	929.7[a]	10,023	-	-	1316.89	3321.02
80/81	146.3[b]	160649	9104	-	2445.95	3180.61
84/85	3075.5[c]	158760	6259	27780	4935.08	2869.10
86/87	4325.5[c]	11275	7201	21959	6129.05	2836.00

a. 4600 kCal/kg
b. 4200 "
c. 4000 "
* 9900 kCal/kg
\# Sp. Gravity = 0.88, 10200 kCal/kg; KL = kilolitre
@ Sp. Gravity = 0.99, 9700 kCal/kg

Table 2 : WBSEB -- Thermal Efficiency

Year	Coal ('000 tonnes)	F.O. (KL)*	LDO (KL)#	LSHS (KL)@	Generation (GWh)	Heat Rate (kCal/kWh)
75/76	3057.8	46032	-	-	4592.98	3292.3
80/81	3420.8	13816	36755	-	5309.61	2793.2
84/85	4351.4	11710	82947	-	6664.68	2740.27
86/87	5506.7	12552	98375	-	8587.74	3042

Table 3 : Gas Turbines

Year	Oil Consumption(KL)	Generation (GWh)	Heat Rate (kCal/kWh)
1975/76	2624	7.22	3508.05
1980/81	75004	179.50	4033.3
1984/85	30448	67.38	4361.81
1986/87	17736	38.32	4467.55

Table 4 : Tamil Nadu -- Load Factor of Steam Thermal Power Stations

Year	Generation (GWh)	Name Plate Capacity (MW)	PLF
75-76	1316.89	540	27.8
80-81	2445.95	960	29.0
84-85	4935.08	1140	49.4
86-87	6129.05	1290	54.2

Table 5 : Tamil Nadu -- Load Factor of Hydro Power Stations

Year	Generation (GWh)	Name Plate Capacity (MW)	PLF
75-76	4405.23	1224	41.08
80-81	4925.73	1369	41.07
84-85	4525.99	1368.95	37.74
86-87	3318.64	1503.95	25.18

Table 6 : West Bengal -- Load Factor of Thermal Power Stations

Year	Generation (GWh)	Name Plate Capacity (MW)	PLF
75-76	4813.57	1397.94	39.3
80-81	6326.95	2028.17	35.6
84-85	8021.32	2764.75	33.1
86-87	9609.90	3069.57	35.7

Table 7 : All India -- Load Factor of Thermal Power Stations

1975-76	52.1
1980-81	44.2
1984-85	50.1
1987-88	56.5

Table 8 : West Bengal -- Load Factor of Hydro Power Stations

Year	Generation (GWh)	Name Plate Capacity (MW)	PLF
A. WBSEB			
75-76	85.03	36.51	26.6
80-81	56.45	38.51	16.73
84-85	131.191	46.51	32.19
86-87	109.19	46.91	26.57
B. DVC*			
75-76	320.63	104	35.19
80-81	344.76	104	37.8
84-85	362.75	104	39.8
86-87	370.73	104	40.69

* Damodar Valley Corporation -- a utility which supplies power to West Bengal and other states in the Eastern Region.

Table 9 : TNEB -- Best & Worst PLF

Year	Capacity	Stn.	Year of Commissioning	Generation (GWh)	PLF
1987/88	210.0	Tuticorin-3	1982	1457	478.94
1988/89	110.0	Ennore-4	1973	255.44	26.51
1987/88	110.0	Ennore-3	1972	483.21	50.01
1988/89	210	Tuticorin-3	1982	1630.98	88.66

Table 10 : West Bengal -- Best & Worst PLF

Year	Capacity	Stn.	Year of Commissioning	Generation (GWh)	PLF
1987/88	210.0	Bandel-5	1982	1003.97	54.43
	120.0	Santaldih-3	1978	192.0	18.21
1988/89	210.0	Kolaghat-2	1985	924.0	50.23
	120.0	Santaldih-3	1978	36.0	3.42

Table 11 : Tamil Nadu -- Transmission & Distribution Losses (GWh)

Year	Net Generation (GWh)	From jointly owned projects (GWh)	Captive Generation (GWh)	Imports from other states (GWh)	Energy Available (GWh)	Energy Sold (GWh)	Losses (GWh)	Loss %
75/76	5517.60	2229.99	8.14	402.53	8158.26	6646.15	1512.11	18.53
80/81	7030.58	2809.80	11.05	1092.50	10943.93	8881.47	2062.46	18.84
84/85	8933.10	4634.31	4.0	219.03	13790.34	1158.69	2631.75	19.08
86/87	8861.85	6082.80	-	70.00	15014.65	12423.71	2590.94	17.26

Table 12 : West Bengal -- Transmission & Distribution Losses

Year	Net Generation (GWh)	From jointly owned projects (GWh)	Captive Generation (GWh)	Imports from other states (GWh)	Energy Available (GWh)	Energy Sold (GWh)	Losses (GWh)	Loss %
75/76	4274.57	-	8.7	2066.75	6350.02	5596.47	753.55	11.87
80/81	5061.27	-	-	1658.53	6719.80	5747.47	972.33	14.47
84/85	6182.71	-	-	2226.66	8409.37	6882.91	1526.46	18.15
86/87	6952.67	612.53	0.12	2134.63	9699.95	8078.04	1621.91	16.72

Table 13 : All India -- Transmission and Distribution Losses

Year	Generated (GWh)	Purchased from non-utilities (GWh)	Import from other countries (GWh)	Total energy sold (GWh)	Losses (GWh)	Losses %
75/76	74675.11	115.77	5.94	60245.81	14526	19.42
80/81	103613.50	115.73	4.63	82409.27	21324.59	20.56
84/85	145209.36	177.38	6.45	114179.01	31214.18	21.47
86/87	173390.18	243.18	169.85	136019.61	37783.70	21.74

Table 14 : All India -- Length of Transmission Lines in ckt km*

	1974	1980	1985	1986
400 kV	-	1452 (.06)	6035 (.18)	7952 (0.23)
220/230 kV	13932 (.91)	30032 (1.27)	44497 (1.38)	47802 (1.41)
132 kV	31715 (2.08)	43591 (1.85)	58643 (1.82)	61083 (1.83)
11/15 kV	475160 (31.28)	717194 (30.4)	986415 (30.71)	1030094 (30.55)
Total	1518884	2351609	3211956	3371216

* As of March 31 of selected years.

Table 15 : West Bengal -- Length of Transmission Lines in ckt-km

	1976	1981	1985	1987
400 kV	-	-	236 (.28)	387 (0.38)
230 kV	-	-	-	-
220 kV	700 (2.31)	724 (1.03)	2122 (2.54)	2762 (2.76)
132	1843 (6.1)	1842 (2.63)	2436 (2.92)	2457 (2.45)
110/90	-	-	-	-
78/66	495 (1.63)	505 (0.72)	812 (0.97)	812 (0.812)
33	3934 (13.02)	4278 (6.11)	4359 (5.22)	4383 (4.38)
22	56 (.18)	60 (0.08)	60 (0.07)	60 (0.06)
15/11	2344 (7.75)	32389 (46.27)	39082 (46.88)	39133 (39.13)
6.6	2303 (7.62)	2697 (3.85)	2702 (3.24)	N.A. -
Upto 500	18537 (61.35)	27503 (39.3)	31551 (37.84)	N.A. -
Total	30212	69998	83360	99988

Table 16 : Tamil Nadu -- Length of Transmission Lines in ckt-km

	1976	1981	1985	1987
400 kV	-	-	-	-
230 kV	1679 (0.60)	2140 (0.64)	3198 (0.95)	3564 (0.94)
220 kV	-	-	-	-
132	-	-	-	-
110/90	5678	4895	7209	7128
78/66	3248 (1.16)	2846 (0.85)	3503 (1.04)	2867 (0.76)
33	2871 (1.02)	3479 (1.04)	4092 (1.22)	3187 (0.84)
22	17472 (6.26)	19047 (5.70)	21890 (6.55)	21821 (5.79)
15/11	40549 (14.53)	45769 (13.70)	52793 (15.81)	51688 (13.71)
6.6	80 (0.02)	-	-	-
Upto 500	207438 (74.34)	255315 (76.46)	283147 (84.79)	N.A. -
Total	279015	333912	375832	376870

Table 17 : Tamil Nadu -- Reserve Margin

Year	Name Plate Capacity (MW)	Peak Availability (MW)	Peak Load (MW)	% Reserve Margin (%)
1981-82	3139	1928	1928*	62.8
1984-85	3344	2054	2054*	62.82
1986-87	3987	2159	2159*	84.64
1988-89	5123	2437	2437*	110

* Restricted peak load.

Table 18(a) : All India -- Reserve Margin

Year	Name Plate Capacity (MW)	Peak Availability (MW)	Peak Load (MW)	% Reserve Margin (%)
1981-82	32347	20121	20121*	60.76
1984-85	42585	36777	26777*	59.03
1986-87	49258	29513	29573*	66.90
1988-89	59091 (estimated)	34779.1	34779.1*	69.90

* Restricted peak load.

Table 18(b) : Regionwise Reserve Margin

Year	Installed cap (MW)	Peak Avail-cap (MW)	Peak Load (MW)*	% Reserve Margin (%)
		(Eastern Region)		
81-82	5349	2836	2836	88.61
84-85	6552	3354	3354	95.3
86-87	7741	3747	3747	106.5
88-89	8392	4260	4260	96.9
		(Western Region)		
81-82	8876	5801	5801	5300
84-85	12928	7398	7398	74.74
86-87	14681.0	7308.7	7308.7	100
88-89	17436	10631.7	10631.7	64.00
		(Southern Region)		
81-82	8131	5509	5509	47.5
84-85	10330	6812	6812	51.6
86-87	12488	7498	7498	66.55
88-89	14418	8856	8856	62.80
		(North-Eastern Region)		
81-82	529	276	276	91.6
84-85	799	363	363	120.0
86-87	892.8	457.4	457.4	95.2
88-89	1028	540.3	540.3	90.26
		(Northern Region)		
81-82	9451	5694	5694	65.98
84-85	11962	7037	7037	69.9
86-87	13462.4	6926	6926	94.37
88-89	17803	10481.0	10481	69.85

* Restricted peak load.

Table 19 : Availability of Hydro Plants

Item	Norm
Planned Maintenance	Nil
Capital Maintenance	3.0%
Forced outage rate	9.5%
Overall peak availability	87.8%

Table 20 : Availability of Thermal Plants (1987-88)

Least duration for annual maintenance (Southern region) 200/210 MW	- 30 days
Least duration for capital maintenance (Southern region) 200/210 MW	- 60 days
Highest duration for annual maintenance (Eastern region) 200/210 MW	- 61 days
Highest duration for capital maintenance (Eastern region) 200/210 MW	- 137 days

Table 21

Percentage loss due to

Forced outages in themal power plants

1986-87	- 19.28% of time
1987-88	- 17.65%

No. of outage per unit

1987-88	- 32.3
1986-87	- 30.7

Table 22 : All India -- Trends in village electrification & pumpset energisation

Year	Villages electrified		Pumpsets energised (No.)
	Number	As a % of total	
1973/74	1,56,729	27.2	24,26,133
1980/81	2,72,625	47.3	43,30,437
1984/85	3,70,332	64.3	57,08,666
1988/89	4,54,288	78.4	76,19,814

Tamil 23 : Tamil Nadu -- Rural Electrification

Year	Villages electrified		Pumpsets energised (No.)
	Number	As a % of total	
1975-76	15509	98.56	7,42,746
1980-81	15586	99.10	9,19,162
1984-85	15700	99.77	10,33,556
1986-87	15735	99.4	11,16,177

Table 24 : West Bengal -- Rural Electrification

Year	Villages electrified		Pumpsets energised (No.)
	Number	As a % of total	
1975-76	9825	25.81	10701
1980-81	14263	37.5	24886
1984-85	19201	50.4	39492
1986-87	21881	57.5	52398

Table 25 : All India -- Captive Generation in Industries

Name of Industry	No. of factories	Installed Capacity (MW)	Energy generated (MW)
A. 1975-76			
a. Sugar	163	300.83	507.615
b. Texitiles	377	258.937	574.885
c. Paper	34	138.728	545.027
d. Iron & Steel	9	512.910	1853.402
e. Chemical	88	110.300	324.609
f. Aluminium	7	143.800	2797.481
Sub-total(a to f)	678	1465.505	6603.019
Total(all industries)	1264	2070.894	6657.122
B. 1980-81			
a. Aluminium	7	153.79	1011.42
b. Chemicals	163	199.188	558.21
c. Fertilizers	26	168.974	571.50
d. Iron & Steel	11	522.890	2149.55
e. Mineral oil & petroleum	15	146.012	505.91
f. Paper	57	198.299	741.31
g. Sugar	227	496.314	738.67
Sub-total(a to g)	506	1885.467	6276.57
Total(all industries)	2223	3041.127	8773.63
C. 1985/86			
a. Aluminium	8	288.5	2151.33
b. Chemicals	330	389.065	908.16
c. Fertilizers	35	343.743	1081.96
d. Iron & Steel	21	623.4	2360.4
e. Mineral Oil and Petroleum	30	303.519	1098.07
f. Paper	121	285.5	837.85
g. Sugar	280	648.413	1066.05
Sub-total (a to g)	825	2882.14	9503.82
Total(all industries)	3648	5419.134	12997.35

Table 26(a) : Aluminium Industry -- Energy requirements in alumina production (per tonne of alumina)

Electricity energy used & end uses	BALCO	HINDALCO	INDAL (Belgaum)	INDAL (Muri)	MALCO
Grinding	N.A.	354	199	303	301
Hydration(b)					
Calcination	N.A.	39	33	34	26
Total	537	393	232	337	327

Table 26(b) : Electric energy use in aluminium production (per tonne of Aluminium)

Plant/ Energy	BALCO	HINDALCO	INDAL (Always)	INDAL (Belgaum)	INDAL	MALCO
Smelter (kWh)	18107	16565	18016(b) 167733(c)	17060	16920	19620
Anode-plant kWh	N.A.	112	N.A.	N.A.	N.A.	N.A.

(b) for 23 kA pot line
(c) for 49 kA pot line

Table 27 : Textile Industry -- Electricity Use

	kWh
Cotton (per meter)	0.9
Polyster (per meter)	-
Juto (per 1000 kgs)	545

Total energy consumption in the Indian Textile Industry.

Year	Electricity (kWh)		
	Textile	Jute	Total
1970-71	3950.5	659.8	4610.3
1979-80	5743.2	700.2	6443.4
1985-86	8348.7	820.2	9168.9

Textile End Consumers about 9% of the commercial energy consumed in the country.

Table 28 : Iron and Steel Industry -- Electricity Use

Year	Electricity	Ingot Steel Production (10^6 kgs)	Sp. Consump. in kWh/10^3 kgs
1980-81	3440	9353	467.8
1984-85	4063	8144	498.9
1988-89	4883	10383	470.3

Table 29 : Energy Intensity of Selected Industries

	1975/76	1980/81	1984/85
A. Basic metals & alloys			
Value added (US # million)	1373.73	1580.43	1824.70
Electricity Use (GWh)	8492.574	8687.99	13054.1
Intensity (kWh/US #)	6.18	5.49	7.15
B. Paper & Paper products			
Value added (US # million)	529.03	570.42	643.30
Electricity Use (GWh)	1272.327	1715.6	2469.42
Intensity (kWh/US #)	2.40	3.00	3.83

Table 30: Total electricity generated (GWh)

	Gross generation	Net Generation
1975-76	-	-
1980-81	81,216	76,122
1984-85	106,447	99,039

Source : Reference 1, page 54.

Gross Generation includes thermal, hydro, gas, oil.
Net Generation is gross generation minus station consumption.

Table 31 : Total electricity sales (GWh)

	TNEB	WBSEB
1975-76	6,422	2,332
1980-81	8,586	3,159
1985-86	10,389	3,850
1988-89*	13,754	4,791

Source : Reference 1, page 37, 38, 39.

* Reference 2 & 3, schedule-3.

Table 32: Average costs of electricity supply

	Average cost of gen. and supply (p/kWh)	Average rate of realisation
1974-75	22.52	18.79
1980-81	41.82	32.30
1985-86	74.59	59.43

Source : Reference 1, page 19.

Table 33 : Break-Up of Expenses (Rs/lakhs)●

	TNEB				WBSEB			
	1975-76	80-81*	85-86	88-89	1975-76	80-81*	85-86	88-89
1. Power purchases		11020	20431 (25)	31638 (23.5)		2130	3727 (9.1)	22687 (34.8)
2. Power generation		6540	23059 (28.1)	41920 (31.2)		4370	13103 (31.9)	12731 (19.5)
3. Repair & Maintainence		-	3824 (4.7)	3548 (2.6)		- -	1483 (3.6)	2592 (4)
4. Employee costs		8630	17158 (21)	25937 (19.3)		2900	7848 (19.1)	10258 (15.7)
5. Administ-ration & general expenses		-	2075 (2.5)	3455 (2.6)		-	1652 (4)	1477 (2.3)
6. Depreciation & related debits		2840	4356 (5.3)	7038 (5.2)		1020	1948 (4.7)	2473 (3.8)
7. Interest & Finance charges		5480	10922 (13.3)	20984 (15.6)		2640	11245 (27.4)	13022 (20)
Total			81825	134520			41006	65240

Source : Reference 2 & 3, Figures in brackets are percentages of Total.

● Rs 1 lakh = Rs 1,00,000
* Reference 1, Income Statement.

Table 34 : Overall Fuel costs per unit of thermal generation (paise/kWh)

	TNEB	WBSEB
1975-76	-	-
1980-81	-	-
1985-86	39.4	28.70
1988-89	52.8	39.01

Source : Reference 2 & 3, Statement 7 and Statement 9.

Table 35 : Fuel cost for coal based thermal generation (p/kwh)

	TNEB		WBSEB	
	Coal	Oil	Coal	Oil
1975-76	-	-	-	-
1980-81	-	-	-	-
1985-86	-	-	-	-
1988-89	52.9	2.0	27.2	5.3

Source : Reference 4 (Annexure 30).

Table 36 : Salaries & Wages

	TNEB		WBSEB	
	Employee costs (Rs mill)	Ratio of S&W to total elec. sold (Rs/MWh)	Employee costs (Rs mill)	Ratio of S&W to total elec. sold (Rs/MWh)
1975-76	-	-	-	-
1980-81	863	100.5	290	91.8
1985-86	1715.8	165.2	784.8	203.8
1988-89	2593.7	188.6	1025.8	214.1

Source : Reference 2 & 3, Statement-1, Revenue Account.

Table 37 : Financial Costs

	TNEB		WBSEB	
	Int. & Finance charges capitalised (Rs mill)	Ratio of financial charges to total elec. sold (Rs/MWh)	Int. & Finance charges capitalised (Rs. mill)	Ratio of financial charges to total elec. sold (Rs/MWh)
1975-76	-	-	-	-
1980-81*	99.8	11.6	138.9	43.96
1985-86	2.9	.28	494.6	128.5
1988-89	547.2	39.78	659.9	137.7

Source : Reference 2 & 3, Revenue Account.

* Due to absence of any information on the interests capitalised, we calculated this figure using.

$$\frac{\text{Interests paid in the year}}{\text{Total long term debt}} \times \text{Capital works-in progress}$$

Table 38 : Revenue from electricity sales (Rs/MWh)

	TNEB		WBSEB	
	Revenue (Rs mill)	Ratio to sales	Revenue	Ratio to sales
1975-76	-	-	-	-
1980-81	2612	304.2	1306	413.4
1985-86	5977	575.3	2889	750.4
1988-89*	8627.3	627.2	4780.5	997.7

Source : Reference 1, page 50,51

* Reference 2 & 3, statement-1 (Revenue A/c)

Table 39 : Average cost of electricity supply (paise/kWh)

	Average cost per unit of electricity sold	
	TNEB	WBSEB
1975-76	-	-
1980-81	43.82	49.0
1985-86	76.42	100.21
1988-89*	89.35	117.58

Source : Reference 1, page 35.

* Reference 2 & 3 statement 1
  Cost = Expenses - Exp capitalised + other debts

Table 40 : Billing effectiveness : Average collection period**

	TNEB	WBSEB
1975-76	-	-
1980-81*	91.25	80.21
1985-86	51.22	89.78
1988-89	46.75	107.89

Source : Reference 2 & 3

* Reference 1, page 52.
** Computed as follows :

$$\frac{\text{Receivable against sale of power (schedule 26)}}{\text{Revenue from sale of power (statement 1)}} \times 365$$

Table 41 : Self-financing ratio

	TNEB		WBSEB	
1980-81*	(44+284-548 -115)/1690	-.198	(-69+102-264 -77)/1033	-.298
1985-86	(278.8+435.6 -1092.2-3537.8/ 4529.6	-.86	(-299+195-1124 -742)/1925	-1.01
1988-89	(413.3+704-2098 -2429)/4789	-.71	(-388+247+ -1302-991)/ 1742	-1.40

Source : Reference 2 & 3.

* Reference 1.

The Self-financing ratio is computed as follows :

$$\frac{\text{Surplus/Deficit (Statement 1) + Depreciation \& related debits (statement 1) - interest \& financial charge (statement 1) - repayments (statement 7)}}{\text{Total capital expenditure (statement 7)}}$$

Table 42 : Working force productivity (no. of employees/GWh)

	TNEB	WBSEB
1975-76	-	-
1980-81	11.0	11.7
1985-86	8.6	10.9
1988-89	6.8	8.5

Source : Annual report on SEB's by Planning Commission (April 1986 & Sept. 1990) in Reference 5 (page 260)

Table 43 : Indebtedness - Long term debt* (Rs lakhs)

	TNEB	WBSEB
1975-76	-	-
1980-81	-	-
1985-86	35,378	17,081
1988-89	31,364	10,951.2

Source : Reference 2 & 3, schedule 32 & 33.

* Computed as follows :

Market borrowings + institutional borrowings + state loans in that year.

Table 44 : Average revenue realized (paise/kWh)

	Consumer Category	TNEB 1975-76	TNEB 80-81	TNEB 85-86	TNEB 88-89	WBSEB 1975-76	WBSEB 80-81	WBSEB 85-86	WBSEB 88-89
1.	Interstate			39.3	41.5				N.A.
2.	Domestic			52.7	55				63.2
3.	Commercial			94.7	91.6				135.79
4.	Industrial HT/LT			79.1	HT* 83.4 LT 98				117.8
5.	Public lighting			40.1	50.9				82.7
6.	Railways			84.2	-				130.4
7.	Irrigation, Agriculture (HT\LT)			11.2	10.4				26.8
8.	Public water works & sewage			44.7	52.7				67.4
9.	Bulk supply			56.5	71.5				94.7

Source : Reference 2 & 3 - Schedule 3.

* HT includes Railway traction.

Table 45 : Social Tariffs - Domestic tariff

	Fixed Charge	Energy Charge		Minimum Charge
TNEB*	55	Rs 4/month service		-
WBSEB**	-	kWh/month	P/KWh	
		first 50	52	Rs 10/-
		Next 50	60	per service
		101->800	70	vice connec-
		more than 800	100	per month

Source : NCPU - Summary of tariff schedules of SEB's.

* effective from 1.4.89
** effective from 1.6.88.

Table 46 : Net Fixed Assets (Rs lakhs)

	TNEB	WBSEB
1975-76	-	
1980-81*	69510	21690
1985-86	103652	75266
1988-89	197131	53581

Source : Reference 2 & 3 - statement 3.

* Reference 1, page 161 & 147.

Table 47 : Capital Productivity (ratio of total elec. sales to net fixed assets)

	TNEB	WBSEB
1975-76	-	-
1980-81	809.6	686.6
1985-86	997.7	1954.96
1988-89	1433.3	1118.3

Table 48 : Index of indebtedness (long term debt/NFA)

	TNEB	WBSEB
1975-76	-	-
1980-81	-	-
1985-86	.34	.23
1988-89	.16	.20

Table 49 : Trends in Annual Growth Rate of GNP, Electricity Generation and percentage of Power Shortages

Year	GNP growth rate (% per annum)	Growth rate of electricity generation (% per annual)	Percent Power shortages
1974-75	-	5.2	14.1
1975-76	-	12.9	10.3
1976-77	-	11.5	5.8
1977-78	7.5	3.4	15.5
1978-79	5.6	12.2	10.3
1979-80	-4.9	2.1	16.8
1980-81	7.2	5.9	12.6
1981-82	5.9	10.2	10.8
1982-83	2.6	5.7	9.2
1983-84	8.0	7.6	10.8
1984-85	3.8	12.0	6.7
1985-86	5.0	8.5	7.9
1986-87	3.9	10.3	9.4
1987-88	3.8	7.5	10.9
1988-89	10.6	9.5	7.7**
1989-90	4-4.5*	12.0#	-

* Anticipated.
\# April to December.
** April to February.

Table 50 : Plan Outlay for the Power Sector

Period	Allocation for the power sector as a percentage of total plan allocation
Ist Plan (1951-56)	13.3
IInd Plan (1956-61)	10.0
IIIrd Plan (1961-66)	14.6
Annual Plans (1966-69)	18.3
IVth Plan (1969-74)	18.6
Vth Plan (1974-79)	18.8
1979-80	18.4
VIth Plan (1980-85)	16.6
VIIth Plan (1985-90)	19.0

S.No.	Name of Scheme		Date of Sanction	Date of Commissioning		Cost estimates (Rs lacs)		Percentage cost overrun
				Original	Actual	Original	Revised	
A. THERMAL PROJECTS								
1.	Panipat -	Unit III	3/78	9/82	11/85	7,293	18,958	60
		Unit IV		3/83	1/87			
2.	Tandon -	Unit I	3/79	9/83	3/88	15,925	47,591	60
		Unit II		4/84	3/89			
		Unit III		10/84	3/90			
		Unit IV		3/85	3/91			
3.	Anapara -	Unit I	1/79	4/83	3/86	22,710	72,102	100
		Unit II		10/83	2/87			
		Unit III		4/84	3/88			
4.	Wanakbori-	Unit IV	6/78	12/82	3/86	20,679	40,570	20
	Extn.	Unit V		6/83	9/86			
		Unit VI		12/83	11/87			
5.	Korba West-	Unit I	3/79	9/83	3/85	12,994	29,375	60
		Unit II		3/84	3/86			
6.	Chandrapur-	Unit I	2/79	3/84	5/85	12,856	27,992	50
	Extn.	Unit II		12/84	3/86			
7.	Raichur-II-	Unit I	4/78	10/82	3/85	15,925	32,542	40
				4/83	3/86			
8.	Neyveli -	Unit I	6/78	10/83	3/86	21,398	55,486	60
		Unit II		4/84	2/87			
		Unit III		10/84	1/88			
9.	Muzzaffur-	Unit I	7/78	7/82	3/85	8,435	22,918	90
	pur	Unit II		1/83	3/86			
10.	Kolaghat-	Unit I	6/73	9/78	7/84			
		Unit II		3/79	12/85	11,559	41,808	50
		Unit III		9/79	8/90			
11.	Durgapur		4/74	6/79	7/85	4,842	9,429	30
12.	Bokaro		10/77	4/82	3/86	6,976	20,644	130
13.	Farakka STPS-I							
		- Unit I	8/79	9/84	1/86	29,000	69,212	-
		Unit II		3/85	12/86			
		Unit III		9/85	8/87			
14.	Patratu -	Unit I	4/74	9/77	3/84	4,200	16,910	180
		Unit II		3/78	3/86			

S.No. Name of Scheme	Date of Sanction	Date of Commissioning		Cost estimates (Rs lacs)		Percentage cost overrun	Percentage time overrun
		Initial	Actual	Initial	Revised		
. HYDRO PROJECTS							
1. Ukai LBC	2/77	-	12/85	305	592	38	-
2. Kadana PSS- Unit I	2/72	-	8/86	2,458	18,451	135	-
- Unit II	10/72	-	8/89				
3. Tillari	6/72	-	6/85	816	5,524	177	-
4. Bhira Tail Race	11/70	-	10/86	841	6,664	177	-
5. Pench - Unit I	12/72	-	6/85	2,828	23,522	241	-
Unit II		-	10/86				
6. Idamalayar	9/73	-	10/85	2,340	7,103	49	-
7. Kakkad	9/76	-	3/90	1,860	6,720	55	-
8. Servalar	7/74	-	10/85	835	4,280	252	-
9. Upper Kolab-Unit I	5/75	-	10/85	5,898	19,801	118	-
Unit II		-	10/86				
10. Rammam - Unit I	4/77	-	10/86	2,419	6,967	82	-
Unit II		-	10/87				
Unit III		-	10/88				
11. Panchet Hill	10/77	-	10/87	1,603	5,435	114	-
12. Chamera St.-I	9/83	-	3/89	80,929	141,988	50	-
13. Upper Sindh-II	1981	-	1989	7,646	15,410	57	-
14. Hasdeo Bango	1984	-	3/90	4,386	9,453	80	-
15. Bansagar Tons	6/84	-	3/90	30,117	52,570	53	-
16. Ujjaini	7/84	-	3/90	1,632	3,340	80	-
17. Balimela Dam	2/77	-	3/90	1,777	8,534	139	-
18. Penna Ahobilam	3/84	-	3/90	1,247	1,900	31	-
19. Nagarjuna Sagar LBC	3/84	-	10/88	3,400	4,855	25	
		-	10/89				
20. Ghatprapha	5/82	-	3/90	1,882	3,530	43	-

S.No.	Name of Scheme	Date of Sanction	Date of Commissioning		Cost estimates (Rs lacs)		Percentage cost overrun	Percentage time overrun
			Initial	Actual	Initial	Revised		
21.	North Koel	3/84	- -	10/87 10/88	2,194	3,488	42	-
22.	Hirakund III	8/82	-	10/86	1,597	3,618	100	-
23.	Lower Borpani	9/79	-	10/86 10/87	3,637	10,293	100	-

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